FIELD OF THE INVENTION

The present invention relates to a method for simulating well tests on a discrete fractured reservoir model.

The method can be implemented for example in the field of oil production by reservoir engineers in order to obtain reliable flow predictions.

A well test is to be simulated in a permeable porous medium (reservoir) crossed through by a network of fractures much more conducting than the porous matrix. Fractured reservoirs constitute an extreme type of heterogeneous reservoirs comprising two very different media, a matrix medium containing the most part of the oil in place and having a low permeability, and a fractured medium representing less than 1 % of the oil in place and highly conducting. The fractured medium itself can be complex, with different series of fractures characterized by their respective density, length, orientation, inclination and opening.

During well testing, the flow rate conditions imposed on the well lead the oil contained in the reservoir to flow towards the well. It is a single-phase (the only mobile phase is the oil) and compressible flow (the rock of the reservoir and the oil fluid are compressible).

For any elementary volume of the reservoir, the pressure of the oil contained in this volume is governed by the following equation, if gravity is not taken into account :

$$\phi.C_T.\frac{\partial P}{\partial t} = div(\frac{K}{\mu}.\nabla P) + Q \qquad (1)$$

where :

ϕ : represents the pore volume,

C_T, the total compressibility (fluid + rock),

K, the permeability of the rock,

μ, the viscosity of the fluid,

Q, the incoming flow, which is zero everywhere except in places where the well communicates with the reservoir, and

P, the unknown pressure.

In order to simulate a well test, whatever the medium, this equation has to be solved in space and in time. Discretization of the reservoir (mesh pattern) is therefore performed and solution of the problem consists in finding the pressures of the meshes with time, itself discretized in a certain number of time intervals.

In the case of a fractured medium, if all the complexity of the fracture network is to be taken into account, it is necessary to have a mesh pattern that represents this network accurately. Furthermore, in such a medium, the permeabilities K are generally much higher in the fractures than in the matrix, and the flows are consequently fast in the fractures and slow in the matrix.

BACKGROUND OF THE INVENTION

Single-phase flow computing tools are currently used; however, they are not applied to the real geologic medium in all its complexity but to a homogenized representation, according to the reservoir model called double-medium model described for example by Warren and Root in "The Behavior of Naturally Fractured Reservoirs", SPE Journal, September 1963. Any elementary volume of the fractured reservoir is thus modelled in

the form of a set of identical parallelepipedic blocks limited by an orthogonal system of continuous uniform fractures oriented in the direction of one of the three main directions of flow (model referred to as "sugar box" model). The fluid flow on the reservoir scale occurs through the fractured medium only, and fluid exchanges take place locally between the fractures and the matrix blocks are not applied to the complex medium. This representation, which does not reproduce the complexity of the fracture network in a reservoir, is however effective but at the level of a reservoir mesh whose typical dimensions are 100 m x 100 m.

It is however preferable to carry out the flow calculations on the "real" geologic model instead of an equivalent homogeneous model, which affords the double advantage of allowing :

- to validate the geologic image of the reservoir built by the geologist from all the information he has gathered on the reservoir fracturation (this validation being performed by comparison with the well test data),
- to reliably test the sensitivity of the hydraulic behaviour of the medium to the uncertainties on the geologic image of the fractured medium.

A well-known modelling method consists in finely meshing the fracture network and the matrix while making no approximation concerning fluid exchanges between the two media. It is however difficult to implement because the often complex geometry of the spaces between the fractures makes it difficult to mesh them and, in any case, the number of meshes to be processed is finally often tremendous. The complexity increases still further with a 3D mesh pattern.

Techniques for modelling fractured porous media are described in patents FR-A-2,757,947 and FR-A-2,757,957 filed by the applicant. The former technique relates to determination of the equivalent fracture permeability of a fracture network in an underground multilayer medium from a known representation of this network, allowing to systematically connect fractured reservoir characterization models to double-porosity simulators in order to obtain more realistic modelling of a fractured underground geologic structure.

The second technique relates to simplified modelling of a porous heterogeneous geologic medium (such as a reservoir crossed through by an irregular network of fractures for example) in the form of a transposed or equivalent medium so that the transposed medium is equivalent to the original medium, according to a determined type of physical transfer function (known for the transposed medium).

SUMMARY OF THE INVENTION

The method according to the invention allows to simulate single-phase flows in a fractured medium.

The object of the method according to the invention is to model fluid flows in a fractured multilayer porous medium by taking account of the real geometry of the fracture network and the local exchanges between the porous matrix and the fractures at each node of the network, and thus to allow simulation of the interactions between the pressure and flow rate variations in a well running across said medium. It is characterized in that the fractured medium is discretized by means of a mesh pattern wherein the fracture meshes are centred on nodes at the various intersections of the

fractures, each node being associated with a matrix volume, and the flows between each fracture mesh and the associated matrix volume are determined in a pseudosteady state.

The matrix volume associated with each fracture mesh in each layer is for example delimited by all of the points that are closer to the corresponding node than to neighbouring nodes.

In order to determine the matrix volume associated with each fracture mesh, each fractured layer is for example discretized in pixels and the distance from each pixel to the closest fracture mesh is determined.

The value of the transmissivity for each fracture mesh – matrix block pair is determined for example by considering that the pressure varies linearly as a function of the distance from the point considered to the fracture mesh associated with the block.

The method according to the invention greatly simplifies calculation of the exchanges between the matrix and the fractures. In fact, there is no specific mesh pattern for the matrix, but each node of the fracture network is associated with a matrix volume, and the flow between each fracture node and its associated block is calculated in a pseudosteady state. The innovation concerns calculation of the volume of each block and of the proportionality coefficient (called transmissivity) that connects the matrix-fracture flow rate to the matrix-fracture pressure difference.

The main advantage of the method according to the invention in relation to methods applied to a finely meshed real fracture network lies, as detailed in the description hereafter, in the considerable reduction in the number of meshes centred on fracture nodes used to solve equation (1). It can be checked that the simulation rate saving in

relation to prior fine-mesh methods is greater than the simple arithmetical ratio of the number of meshes used in both cases.

BRIEF DESCRIPTION OF THE DRAWINGS

Other features and advantages of the method according to the invention will be clear from reading the description hereafter of a non limitative realisation example, with reference to the accompanying drawings wherein :

- Figure 1 shows an example of a 2D fracture mesh, FM,
- Figure 2 shows an example of a 2D matrix block, MB,
- Figure 3 shows an imposed flow rate variation curve F(t) in a well test, and
- Figure 4 shows an example of a fracture network for which the method according to the invention leads to a radical reduction in the number of meshes to be processed.

DETAILED DESCRIPTION OF THE METHOD

1) Fracture network discretization

The method comprises meshing the multilayer fractured reservoir modelled for example by means of the fractured reservoir modelling technique described notably in the aforementioned patent FR-2,757,947, assuming that the fractures are substantially perpendicular to the layer boundaries.

In order to form this mesh pattern, all the fracture intersections or nodes CN are located (Fig.1) and fracture meshes are formed by associating a single matrix block with each node. For the purpose of 3D modelling, additional nodes have to be added in the neighbouring layers in order to take account of the fractures that run across several of

them. The computing nodes thus defined constitute the centre of the fracture meshes FM. The meshes are given boundaries such as the ends of the fractures on the one hand and the midpoint of the segments connecting the computing nodes on the other hand. Considering these boundaries imposed on the meshes, their volume ϕ can be calculated (see relation 1). Calculation of the connections between fracture meshes (transmissivities) used for calculation of the inter-mesh flows can be carried out according to the method described in the aforementioned patent FR-2,757,947.

2) Matrix medium discretization

Discretization of the matrix medium consists in assigning a rock volume to each fracture mesh. During dynamic simulation, exchanges between the matrix and the fractures will be calculated in the pseudosteady state (exchange flow proportional to the pressure difference) between each fracture mesh and its associated single matrix block.

For calculation of these matrix volumes, the problem is dealt with layer by layer, which amounts to disregarding the vertical flows in relation to the horizontal flows in the matrix.

For a given layer, the blocks are defined as follows :

- the block heights are equal and fixed to the height of the layer,
- in the plane of the layer, the surface area of the block associated with a fracture mesh is all the points that are closer to this fracture mesh than to another one.

Physically, this definition implies that the boundaries at zero flow in the matrix are the equidistance lines between the fracture meshes. This approximation is valid if the

neighbouring fractures are at very close pressures, which is true in the presence of highly conducting fractures in relation to the matrix.

a) Block geometry

In order to determine the geometry of the blocks in a given layer, a two-dimensional problem consisting in finding, for each fracture mesh, the points that are closer to this mesh than to another one has to be solved. This problem is solved by using for example, but preferably, the geometric method described in the other aforementioned patent FR-2,757,957, which allows, by discretizing the fractured layer into a set of pixels and by applying an image processing algorithm, to determine the distance from each pixel to the closest fracture. During the initialization phase of this algorithm, value 0 (zero distance) is assigned to the pixels belonging to a fracture and a high value is assigned to the others. Furthermore, if the number of the fracture mesh to which each fracture pixel belongs is given in this phase, the same algorithm finally allows to determine, for each pixel :

- the distance from this pixel to the closest fracture mesh,
- the number of the closest fracture mesh.

All of the pixels having the same fracture mesh number constitute the surface area of the matrix block associated with this mesh. Multiplying this surface area by the height of the layer allows to obtain the volume of the block associated with the mesh. Figure 2 shows an example of a thus obtained 2D matrix block.

By construction, the sum of the surface areas of the blocks is equal to the total surface area of the layer, which guarantees that no volume is added to or taken from the layer.

For each matrix block, the image processing algorithm also gives the distance from each pixel of the block to the associated fracture mesh. This data is used to calculate the transmissivity between the fracture mesh and the matrix block.

b) Matrix-fracture transmissivity

On the assumption of a pseudosteady state where the exchange flow is considered to be proportional to the difference in the pressures of each one of them, we have the following relation :

$$F_{mf} = \frac{T_{mf}}{\mu}.(P_m - P_f) \quad (1)$$

where :

F_{mf} is the matrix-fracture flow,

T_{mf}, the matrix-fracture transmissivity,

μ, the viscosity,

P_m, the pressure of the matrix block, and

P_f, the pressure of the associated fracture mesh.

On the assumption of a pseudosteady state, the value of transmissivity T_{mf} is constant during simulation. This value is here calculated for each fracture mesh – matrix block pair.

For this calculation, it is assumed that, in the matrix block, the pressure varies linearly as a function of the distance from the point considered to the fracture mesh associated with the block. The transmissivity is defined as follows :

$$T_{mf} = \frac{21.H.K}{D} \qquad (2)$$

where :

l is the length of the fractures in the fracture mesh,

H, the height of the layer (and of the matrix block),

K, the permeability of the matrix, and

D, the distance from the fractures for which the pressure is the mean pressure of the block.

l, H and K are known (factor 2 comes from the fact that the fracture has two faces). Calculation of D is made from the information provided by the image processing algorithm concerning the distances from the pixels to the closest fractures. In fact, according to the hypothesis of linear variation of the pressure as a function of the distance to the fracture, we have :

$$D = \frac{1}{S}.\int_S d(s).ds \qquad (3)$$

where S is, in 2D, the surface area of the matrix block and d(s) is the function giving the distances between the points of the matrix block and the associated fracture mesh.

In terms of pixels, we thus simply have :

$$D = \frac{1}{N}.\sum_N d_n \qquad (4)$$

where N is the number of pixels of the matrix block and d_n the distance from pixel n to the fracture mesh.

3) Well representation

A well is represented by its geometry on the one hand and by the flow rate constraints imposed thereon with time on the other hand.

a) Geometry

A well consists of a series of connected segments that intersect the network fractures. The geometric representation of a well is therefore a 3D broken line. Some segments of this broken line communicate with the reservoir. The points of communication between the well and the network are the points of intersection of these segments communicating with the fractures.

b) Flow rate constraints

The flow rate constraints are imposed at the point where the well enters the fractured medium. They are entered by the user in the form of a step function giving the flow rate as a function of time. The flow rate change times of the well indicate the various periods to be simulated.

For a conventional well test (Fig.3), a flow rate F(t) is imposed for a first period after which the well is closed (zero flow rate) and the pressure buildup is observed in the well.

4) Dynamic simulation

During dynamic simulation, the simulated period of time is split up into time intervals whose duration ranges, for a well test, between 1 s (just after opening or closing of the well) and some hours.

Passage from the time n (where all the pressure values are known) to the time n+1 is achieved by solving, in all the meshes and blocks of the reservoir, the following equation which corresponds to relation 1 once discretized :

$$\phi_i.C_T.\frac{P_i^{n+1}-P_i^n}{t^{n+1}-t^n}+\sum_j\frac{T_{ij}}{\mu}.(P_i^{n+1}-P_j^{n+1})=Q_i \qquad (5)$$

where :

i, the number of the mesh or of the block,

j, the number of the mesh or of the block next to i,

P^n, the pressure at the time n,

t^n, the time at the time n,

Q_i, the flow entering i, and

T_{ij}, the connection transmissivity between i and j.

Apart from the pressures, the terms of this equation are known. The pore volumes of the fracture meshes and of the matrix blocks (ϕ_i) are known by means of the mesh pattern, the fracture-fracture and matrix-fracture transmissivities (T_{ij}) are calculated as described above and flow rates (Q_i) are zero everywhere except at the well-reservoir connections where they are imposed.

a) Elimination of the unknowns relative to the matrix

Equation (6) can be solved by inversion of a linear system where the unknowns are the pressures of the fracture meshes and the pressures of the matrix blocks at the time n+1.

However, since each matrix mesh is only connected to one matrix block and since the blocks are not connected to each other, it is possible to eliminate the unknowns of the blocks of the system whose size is then divided by 2.

In fact, for a matrix block, equation (6) is expressed as follows :

$$\phi_m.C_{Tm}.\frac{P_m^{n+1}-P_m^n}{t^{n+1}-t^n}+\frac{T_{mf}}{\mu}.(P_m^{n+1}-P_f^{n+1})=0 \qquad (6)$$

subscripts m and f denoting the matrix and the fracture respectively, and C_{Tm} being the total compressibility of the matrix.

We have $C_{Tm} = c_m + Sw.c_w + (1\text{-}Sw).c_o$, where Sw is the residual water saturation in the matrix, c_m the compressibility of the matrix, c_w the compressibility of the water and c_o the compressibility of the oil, and ϕ_m is the pore volume of the matrix block, i.e. the volume of the block multiplied by the porosity of the matrix.

We deduce therefrom that :

$$P_m^{n+1}=\frac{A_m}{A_m+U_m}.P_m^n+\frac{U_m}{A_m+U_m}.P_f^{n+1} \qquad (8)$$

with :

$$\begin{cases} A_m=\dfrac{\phi_m.C_{Tm}}{t^{n+1}-t^n} \\ U_m=\dfrac{T_{mf}}{\mu} \end{cases}$$

By transferring this expression into the equation relative to the fracture mesh, we obtain :

$$\left[A_i + \frac{A_m.U_m}{A_m + U_m} + \sum_j U_j\right].P_i^{n+1} - \sum_j \frac{T_{ij}}{\mu}.P_j^{n+1} = Q_i + A_i.P_i^n + \frac{A_m.U_m}{A_m + U_m}.P_m^n \qquad (9)$$

where i is the number of the fracture mesh considered, j the numbers of the fracture meshes connected to i, and m the number of the block associated with fracture mesh i.

Furthermore, we have :

$$A_i = \frac{\phi_i.C_{Tf}}{t^{n+1} - t^n}$$

where C_{Tf} is the total fracture compressibility : $C_{Tf} = c_f + c_o$.

Reduction of the number of unknowns by a factor 2 is a further advantage of the present method. The solution time for a linear system develops approximately like the square of the number of unknowns, and consequently elimination of the matrix unknowns leads to a considerable saving in the rate of simulation of a well test on a fractured network.

b) Time interval solution algorithm

The general algorithm for solving a time interval consists in forming a linear system corresponding to equation (9) relative to any fracture mesh i, in solving this linear system and in updating the unknowns.

The stages of this algorithm are as follows :

- Forming the linear system with calculation of the terms of equation (9)

  Calculation of the fracture medium contribution

  accumulation term (A_i)

connection between fracture meshes (T_{ij}/μ)

well boundary conditions (Q_i)

Calculation of the matrix medium contribution

accumulation term (A_m)

matrix-fracture connection term (U_m)

- Solving the linear system (so as to find the fracture pressure values at the time n+1) by means of the iterative conjugate gradient algorithm (CGS)

- Updating with calculation of the matrix block pressures using equation (8), and time interval management.

c) Time interval management

During well test simulation, the time intervals are generally very short after opening or closing of the well, because the pressure variations are high at these times. Later, the time intervals can be longer when the pressure variations are lower.

Management of the time intervals consists in connecting the duration of the time interval n+1 to the maximum pressure variation observed during time interval n. The user must therefore provide the following data :

Initial time interval : dt_{ini}

Minimum time interval : dt_{min}

Maximum time interval : dt_{max}

Lower limit of pressure variation : dp_{min}

Upper limit of pressure variation : dp_{max}

Time interval increase factor : rdt + (>1)

Time interval reduction factor : rdt - (<1).

From these values, management of the time interval is performed as follows :

At the time t_n, the majorant of the pressure variations in the fracture meshes and the matrix blocks during time interval n is calculated (i.e. between times t^{n-1} and t^n). According to the value of this pressure variation dp, the time interval is either :

- increased by a factor rdt+ if $dp < dp_{min}$,
- decreased by a factor rdt- if $dp > dp_{max}$,
- unchanged in the other cases.

After each well flow rate condition change, the time interval is re-initialized to the value dt_{ini}. Furthermore, an optimization is performed at the end of the simulation period : if tf is the time to be simulated to reach the end of the period and dt the planned time interval, the time interval selected is $\min(t_{f2},dt)$.

5) Simulation input data

a) Fracture network

The geometry of the fracture network and the attributes of the fractures (conductivity, opening) are given in the form of a file as in the method described in the aforementioned patent FR-2,757,947.

b) Petrophysics

The petrophysical data to be provided are as follows (the unit is given between parentheses) :

- compressibility of the fracture network (c_f in bar^{-1})
- compressibility of the matrix (c_m in bar^{-1})
- matrix permeability (K in mD)
- matrix porosity (ϕ_m dimensionless).

The data in question are considered to be homogeneous on the fractured medium considered.

c) Fluids

The data relative to the fluids contained in the fractured medium concern the oil (mobile) and the water (immobile) that is always present in residual amounts in the matrix :

- residual water saturation in the matrix (Sw dimensionless)
- compressibility of the water (c_w in bar^{-1})
- compressibility of the oil (c_o in bar^{-1})
- viscosity of the oil (μ in cpo).

d) Well

The data relative to the well are :

- its geometry, in the form of a series of connected segments
- the imposed flow rates, in the form of a curve giving the imposed flow rate as a function of time.

e) Time management

The values to be provided are the values already defined in the chapter relative to the time interval management : dt_{ini}, dt_{min}, dt_{max}, dp_{min}, dp_{max}, rdt+ and rdt-.

Comparative meshing example

The following comparative example illustrates the meshing simplification and the correlative saving in flow calculating time that can be obtained by implementing the method. By way of comparison, it has been observed that the fractured zone shown in Fig.4, that normally would have been meshed with 80,000 meshes with conventional meshing techniques, can be meshed here with about 4000 meshes only.